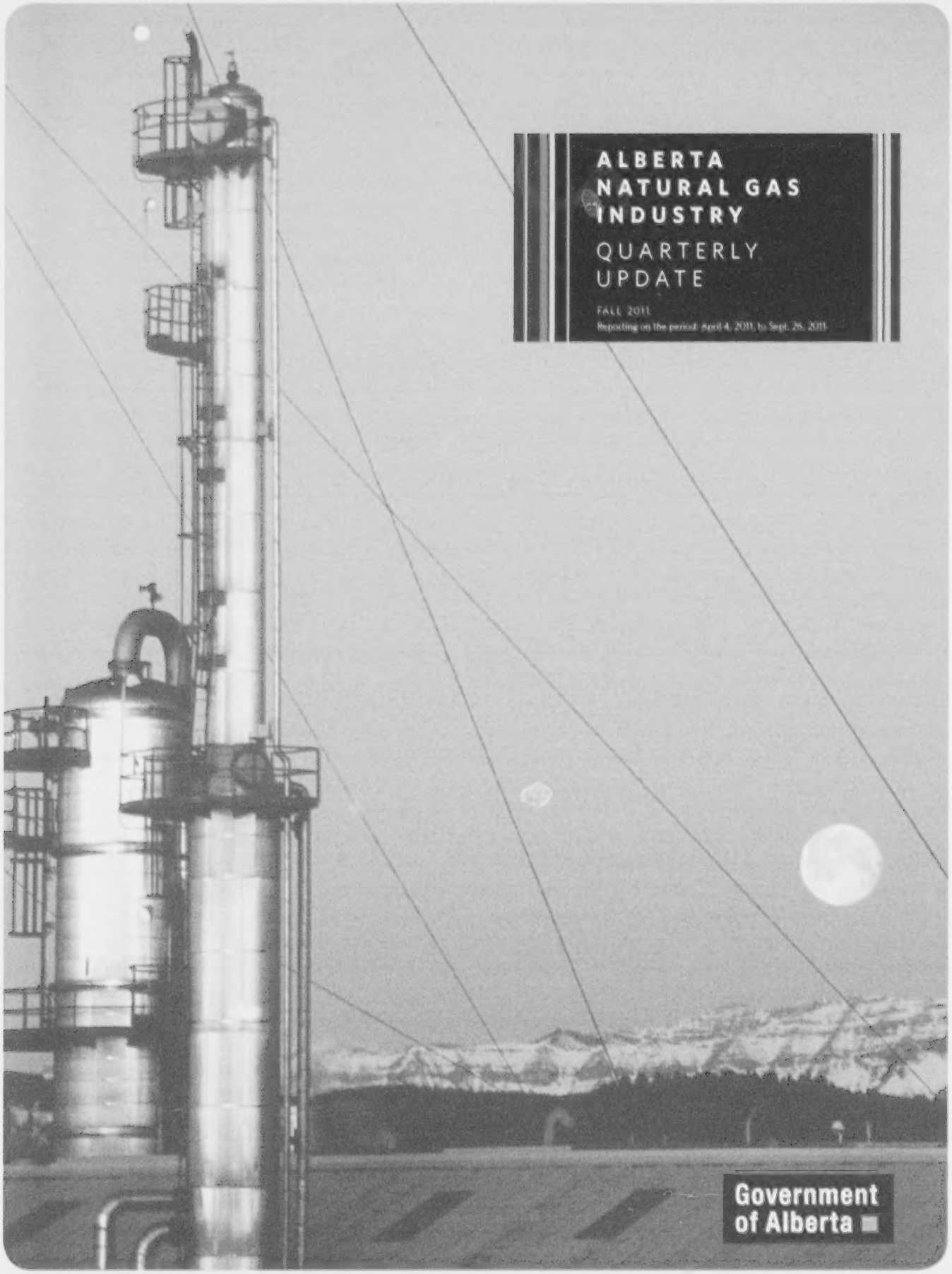

ALBERTA NATURAL GAS INDUSTRY QUARTERLY UPDATE

FALL 2011

Reporting on the period: April 4, 2011, to Sept. 26, 2011

Government of Alberta

All about natural gas

Background of an important western Canadian resource

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Natural gas has been a key part of the Canadian economy and energy mix for many decades, and the Western Canadian Sedimentary Basin (WCSB)—and more specifically Alberta—has led the way.

Canada is the third-largest natural gas producer in the world, with about 80 per cent of the country's gas being produced in Alberta. In 2010, Alberta produced 4.1 trillion cubic feet of marketable natural gas, including production of approximately 3.8 trillion cubic feet from conventional sources and 0.3 trillion cubic feet from coalbed methane (CBM).

According to provincial figures, at the end of 2010, remaining established reserves of conventional natural gas stood at 36.4 trillion cubic feet while remaining established CBM gas reserves stood at 2.4 trillion cubic feet. Reserve additions as a result of new drilling replaced 46 per cent of 2010 gas production. The province estimates the remaining ultimate potential of marketable conventional natural gas at 74 trillion cubic feet.

Although conventional natural gas remains a very important part of western Canadian production and Canada's natural gas supply, a new era is upon us. The industry has now advanced new technology, such as horizontal drilling and multistage fracturing, to the point that allows for development of natural gas from a new source—unconventional natural gas resources. Aside from CBM, Alberta's unconventional natural gas resources include tight gas (natural gas trapped in low-permeability sedimentary rocks, such as sandstone or limestone) and shale gas (trapped in shale rock).

The Canadian Society for Unconventional Gas has estimated that the recoverable, marketable portion of Canada's unconventional resource is from 376 trillion cubic feet to 947 trillion cubic feet. Remaining gas in place in conventional reservoirs is estimated to be 692 trillion cubic feet, and 357 trillion cubic feet of that resource is expected to be recoverable and marketable, with a total marketable resource from both conventional and unconventional resources of 733 trillion cubic feet to 1,304 trillion cubic feet.

Most of the unconventional natural gas resources occur within the WCSB, a thick package of oil and gas prone rocks that cover much of Alberta, Saskatchewan, parts of British Columbia, southwestern Manitoba and northwards into the Northwest Territories.

But there's more to the province's natural gas industry than drilling wells and producing resource, as to make it accessible to Albertans and for export to other markets, a vast infrastructure network is required. Approximately 97 per cent of all oil and gas products move by pipelines in Canada, representing more than three million barrels of crude oil and over 15 billion cubic feet flowing every day through Canada's 580,000 kilometres of pipelines. And this vital transportation network is centred largely in Alberta.

Approximately 70 per cent of natural gas produced in Alberta is exported to other provinces and the United States. Alberta is the largest supplier of natural gas to the United States and currently delivers all of its exports (excluding Canadian provinces) to its southern neighbours, the majority of which goes to the Midwest. Disposition of Alberta's natural gas production in 2010 was approximately:

- 45 per cent to the United States;
- 29 per cent within Alberta; and
- 26 per cent to rest of Canada.

Alberta's natural gas pipelines deliver natural gas across the provincial border to the Canadian Mainline, B.C. System, the Foothills System and others, connecting provincial energy production to locations as far away as the ports of Metro Vancouver and Prince Rupert and various hubs in the United States.

There are over 392,000 kilometres of energy-related pipelines (including oil and natural gas) as well as extensive storage facilities in the province. This infrastructure is an essential lifeline linking Alberta's natural gas resource to national and U.S. markets.

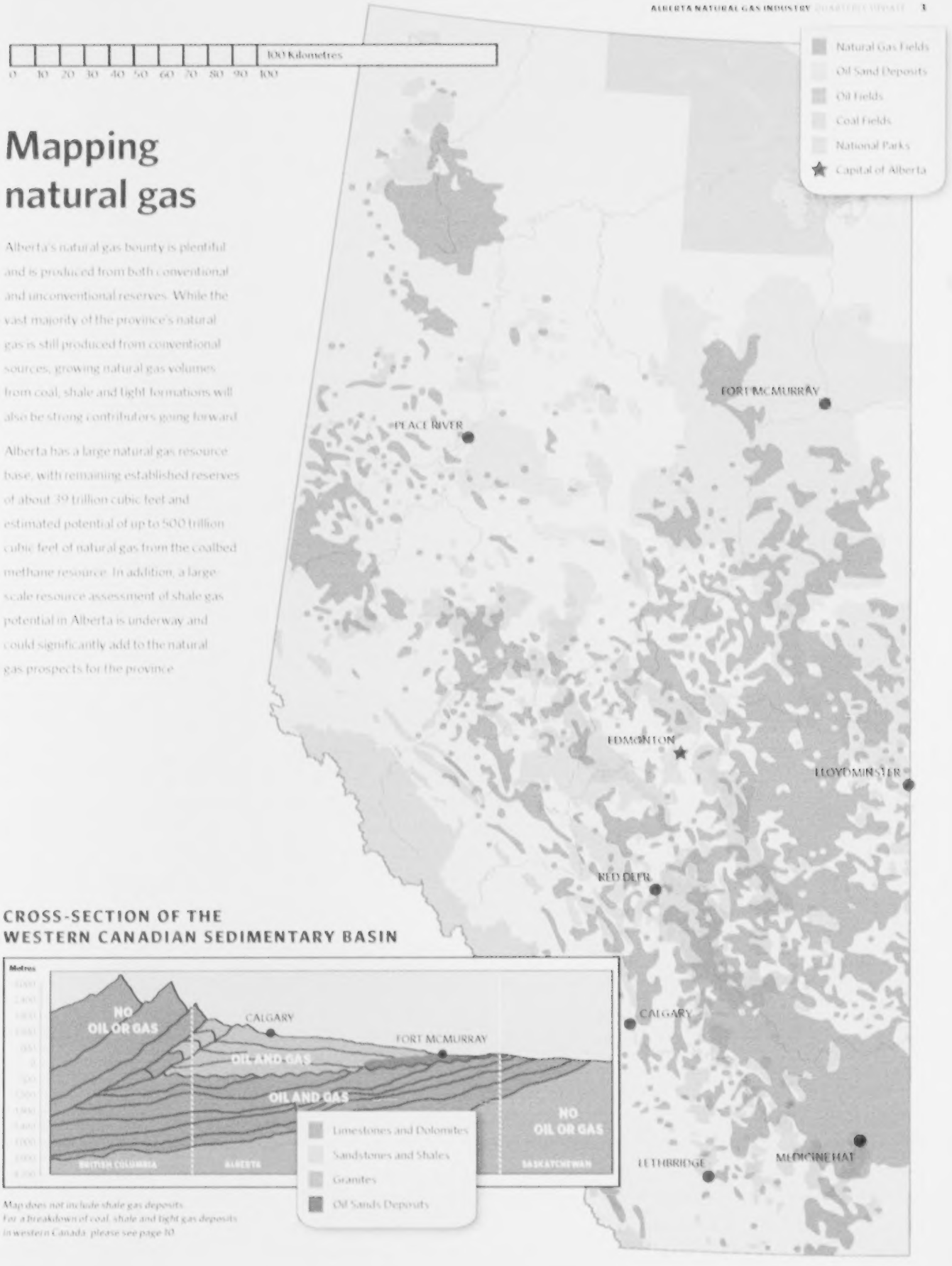
On the environmental front, Alberta has received international attention for its successes in natural gas flaring and venting reductions. Since 1996, solution gas flaring in Alberta has been reduced by 76 per cent. In 2007, the upstream oil and gas industry conserved nearly 96 per cent of all solution gas produced in Alberta for use and sale, rather than flaring and venting it.

By reducing the amount of natural gas that is wasted, Alberta helps ensure that it makes the most effective use of its natural gas resources, and continues the province's record as one of the global leaders in conservation and flaring reductions. ■

Mapping natural gas

Alberta's natural gas bounty is plentiful and is produced from both conventional and unconventional reserves. While the vast majority of the province's natural gas is still produced from conventional sources, growing natural gas volumes from coal, shale and tight formations will also be strong contributors going forward.

Alberta has a large natural gas resource base, with remaining established reserves of about 39 trillion cubic feet and estimated potential of up to 500 trillion cubic feet of natural gas from the coalbed methane resource. In addition, a large-scale resource assessment of shale gas potential in Alberta is underway and could significantly add to the natural gas prospects for the province.



CROSS-SECTION OF THE WESTERN CANADIAN SEDIMENTARY BASIN

Map does not include shale gas deposits. For a breakdown of coal, shale and tight gas deposits in western Canada, please see page 10.

Government update

NEW WEST PARTNERSHIP BETWEEN ALBERTA, BRITISH COLUMBIA AND SASKATCHEWAN

In April 2010, Alberta, British Columbia and Saskatchewan signed the New West Partnership, a new and far-reaching economic partnership between the governments of those provinces. The three provinces committed to ongoing collaboration on innovative ways to strengthen the economy of the West. The partnership focuses on four areas key to economic growth:

- A comprehensive economic agreement, which will remove remaining barriers to trade, investment and labour mobility, further enhancing the competitiveness of Canada's western provinces;
- An international cooperation agreement, which will see the three provinces cooperate on trade and investment missions to international markets, and share foreign market intelligence to advance joint interests and increase business competitiveness;
- An innovation agreement, which will enable provincial innovation efforts to be coordinated to better attract investment and talent, helping build critical mass of innovation activities in the West; and
- A procurement agreement, which will enable the provinces to capitalize on their combined buying power through the joint procurement of goods and services.

For the first time, this unique collaboration has allowed Alberta, Saskatchewan and British Columbia to participate in a joint consultation with the petroleum and natural gas industry to identify barriers and opportunities. Ten major industry associations participated in this initiative. In addition, a joint strategy to promote energy trade and improved access to Asian markets is being developed.

ENHANCING ALBERTA'S COMPETITIVENESS

In May 2011, a partnership of government and Alberta business leaders identified 18 priority actions to make Alberta's economy more competitive. In its report, *Moving Alberta Forward*, the Alberta Competitiveness Council recommended sector-specific actions that include leveraging and enhancing the Alberta Natural Gas Hub. The report stated government will work with industry to:

- Develop a proposal for the western Canadian natural gas and natural gas liquids hub to highlight the benefits of participating in the hub, and to promote the hub concept to the western Canadian and northern regions;
- Develop an agreement with western provinces on the creation of a western Canadian natural gas and natural gas liquids hub;
- Implement a new regulatory convention to provide a framework that is attractive to all interested jurisdictions (including western provinces, the federal government and other gas producing areas such as the Canadian North and Alaska); and
- Develop the concept for a natural gas liquids trading hub in Alberta.

PROVINCE SUPPORTS SIX INNOVATIVE ENERGY PROJECTS

The Government of Alberta is funding six innovative energy projects through the Innovative Energy Technologies Program (IETP) as part of its commitment to establish the province as a world-class centre for responsible energy development.

The successful projects were submitted by Cenovus Energy Inc., Encana Corporation, Laricina Energy Ltd., Pengrowth Energy Corporation and Penn West Exploration. The projects address a variety of research interests, such as advancing production technologies to produce bitumen in reservoirs that are not yet commercial, better understanding of coalbed methane production, and expansion of new enhanced oil and gas recovery technologies into previously inaccessible oil and gas deposits.

The six projects will receive royalty adjustments totalling up to $27.5 million under the fourth and fifth rounds of the IETP. This is in addition to the $133.3 million already allocated to 31 previously approved projects. The project descriptions and additional information on the IETP can be found at www.energy.alberta.ca/Oil/docs/IETP4and5.pdf.

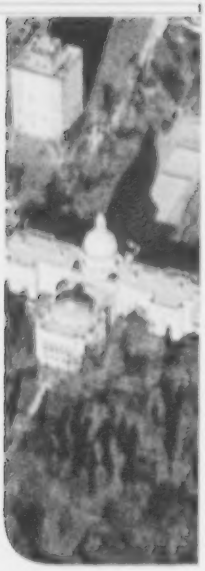
With the successful completion of rounds four and five, the IETP is now open for another round of applications (round six). Applications will be accepted until September 30 with the expectation that successful applicants will be notified by the end of the year. Further details, including the application form, can be accessed at: www.energy.alberta.ca/Oil/768.asp.

INTEGRATED ENERGY RESOURCE REGULATOR

In May 2011, a discussion document called Enhancing Assurance: Developing an Integrated Energy Resource Regulator was created by the Government of Alberta to provide insight and greater detail regarding the move to a single regulator for Alberta's energy sector. The report looks at the operation, key regulatory functions and processes of the single regulator.

The integration of regulatory responsibilities provides an opportunity to enhance energy sector regulation based on the principles of effectiveness, efficiency, adaptability, predictability, fairness and transparency. The report is not, however, a representation of Government of Alberta policy, and no decisions have been made with respect to the subject matter.

Stakeholders and interested members of the public are encouraged to review and consider the report. The report is available at www.energy.alberta.ca/Initiatives/RegulatoryEnhancement.asp.



After moving forward with this initiative, the Alberta government will be engaging the stakeholders who informed the recommendations of the Regulatory Enhancement Task Force. Earlier this year, the Task Force completed a comprehensive upstream oil and gas regulatory review and recommended system-level reforms.

SHALE GAS RESOURCE ASSESSMENT

A large-scale resource assessment of shale gas potential in Alberta led by the Energy Resources Conservation Board (ERCB) is underway. Since 2007, the ERCB has been collecting shale gas data for various formations in Alberta, based on interest and activity from industry. It is anticipated that the resource potential of some formations will be completed in 2011.

PLANNED LNG PROJECTS IN WESTERN CANADA

The second round of the National Energy Board (NEB) hearings into the application from KM LNG Operating General Partnership (KM LNG) for an export licence to ship liquefied natural gas to Asia through Kitimat, B.C., took place in Calgary in July. The first round of the hearings was held in June in Kitimat.

Kitimat LNG is 40 per cent owned by KM LNG and its managing partner Apache Canada Ltd., 30 per cent owned by EOG Resources Canada Inc., and 30 per cent owned by Encana Corporation. KM LNG is the operator.

Kitimat LNG will include natural gas liquefaction, LNG storage and marine on-loading facilities. Natural gas will be delivered via a pipeline lateral of approximately 14 kilometres from the Pacific Trail Pipelines, which will connect to the existing Spectra Energy Westcoast Pipeline system.

The NEB also announced in July that it will hold a public hearing to consider an application submitted by BC LNG Export Co-operative LLC (BC LNG) for a 20-year licence to export liquefied natural gas (LNG) from Canada to Pacific Rim markets. This application is based on projections that the demand for natural gas in Pacific Rim markets will continue to increase substantially over the next 20 years. In its application, BC LNG is requesting authorization to export up to 18 million tonnes of LNG annually.

The board will consider, among other issues, export markets and natural gas supply, transportation arrangements, and the status of regulatory authorizations. The board will also consider the potential environmental effects of the proposed exportation, and any social effects directly related to those environmental effects.

NATURAL GAS USE IN THE CANADIAN TRANSPORTATION SECTOR DEPLOYMENT ROAD MAP

The Natural Gas Use in the Canadian Transportation Sector Deployment Road Map initiative was launched in March 2010 by Natural Resources Canada. It brought together stakeholders from governments, industry – including gas producers, transporters, distributors, vehicle and equipment manufacturers, and end users – as well as representatives from environmental non-governmental organizations and academia. This process provided a platform for stakeholders to discuss the potential for natural gas use across the medium- and heavy-duty transportation sector, explore strategies for overcoming barriers associated with its use, and develop recommendations for deployment.

The initiative focused on expanding the use of natural gas across the transportation sector, and represents an important contribution to deliberations toward a broader strategy to reducing greenhouse gas emissions. The pdf version of the report is available for download on the following website: oee.nrcan.gc.ca/transportation/alternative-fuels/resources/roadmap.cfm?attr=16.

ALBERTA ENVIRONMENT MINISTER LEADS CANADIAN SHALE GAS WATER MANAGEMENT INITIATIVE

Alberta Environment Minister Rob Renner spearheaded Canada's first industry-wide initiative focused on benchmarking best practice for water management in shale gas production. Key operators, including Shell Canada, Nexen Inc., Encana and Talisman Energy Inc., are already on board with the initiative and are sharing their studies on improving water sourcing, treatment, recycling and disposal in shale gas production.

The Shale Gas Water Management Initiative Canada 2011, held September 21–22 in Calgary, was the third water management initiative of its kind in the global series designed for shale gas operators. The initiative offered practical solutions at the level of water sourcing, management, treatment, disposal and recycling for Canadian shale gas production.

The speaker panel consisted of over 25 industry experts, including Shad Watt, director, shale gas development for Nexen. He explained how the company has successfully sourced the large volumes of water required for hydraulic fracturing in the most timely and cost-effective way.

This initiative represented a unique opportunity for shale gas operators to:

- Adopt cost-effective water sourcing strategies;
- Develop optimal treatment, reuse and disposal technologies;
- Examine the viability of alternative water sources and strategies; and
- Maximize the amount of flowback and produced water reused for shale gas completions. ■

What's new in natural gas

Key updates from fall 2011

PRODUCERS SPENDING BIG AT ALBERTA LAND SALES

The Alberta government surpassed its oil and gas land sale bonus revenue from all of last year after a sale of $416.06 million rolled into government coffers at the August 24 auction, moving the year-to-date total into second place all time with eight sales left in 2011.

With this latest total, the province has collected $2.73 billion in bonus revenue on 3.09 million hectares so far in 2011, already displacing last year's $2.41 billion total for second place. For the full calendar year in 2010, Alberta sold a total of 3.93 million hectares. Top spot is held by the 2006 tally, when the government attracted $3.14 billion, thanks to heavy spending for oil sands acreage.

The August 24 land sale generated an average price of $1,615.83 with 257,198 hectares sold. A solid block of land that was sold in northern Alberta in the Fox Creek area, northwest of Edmonton, appeared to be related to continuing interest in the Duvernay. This is where nearly all the spending happened, with 12 different licences in the general area drawing total bonus bids of $416.2 million.

Highlights of Alberta land sale activity in the first half of 2011 included a monster June 1 sale of $854.03 million, which established a new record for bonus revenue at a single auction, surpassing the $651.4 million paid at the Feb. 8, 2006, sale.

Duvernay potential dominated the June 1 sale with huge investments for land in west-central Alberta, northwest of Red Deer. Since late 2009, land sale activity for the Duvernay shales has gone into overdrive, with over $1.4 billion spent to purchase more than one million net acres of land throughout Alberta, mainly by major companies such as Encana Corporation.

INDUSTRY FOCUS TURNING TO LIQUIDS-RICH NATURAL GAS

According to the Energy Resources Conservation Board's (ERCB) annual industry review released in June, as a result of low natural gas prices, Alberta's natural gas producers are increasing their attention on developing natural gas liquids (NGLs)-rich gas pools because the prices of NGLs, with the exception of ethane, track the price for crude oil.

Despite weak levels of natural gas drilling and new well connections, the decline in the production of Alberta's propane, butanes and pentanes plus in Alberta appears to be slowing down as a result of the increased focus by industry on developing liquids-rich natural gas pools.

Propane, butanes and pentanes plus production declined by 5.6 per cent, 3.1 per cent and 3.5 per cent respectively, in 2010 over 2009. This compares to the decline rates in 2009 of 6.4 per cent, 2.8 per cent and six per cent, respectively.

In 2010, the Petroleum Services Association of Canada (PSAC) designated Area 2 (foothills front) experienced a 16 per cent increase in the number of new gas well connections. This area has the largest remaining extractable liquid reserves in the province. PSAC Area 3 (southeastern Alberta), known for its dry gas production, experienced a 10 per cent decrease in new well connections.

The shift by industry to develop pools with gas liquids is expected to continue, which will result in higher gas liquids production than previously forecast, the board said.

Total remaining reserves of extractable NGLs decreased by 3.7 per cent to 761.3 million cubic metres (16.4 billion barrels) compared with 2009 because of the decline in natural gas reserves. Fields that have contributed significantly to this decrease are Beaver River, Caroline, Cecilia, Kakwa and Wayne-Rosedale.

Remaining established reserves of ethane declined rapidly from 1996 to 2003, then levelled off thereafter as more ethane was extracted from raw gas. In 2010, extraction of specification ethane was 12.5 million cubic metres compared with 12.8 million cubic metres in 2009.

The percentage of ethane volumes that have been extracted has been increasing over time. In 2010, there was a significant increase to 63 per cent recovered from 56 per cent in 2009. The ERCB estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted.

For the second year in a row, remaining provincial marketable gas reserves declined as additions of 82.8 billion cubic metres (slightly more than in 2009) did not replace 2010 production of 116 billion cubic metres.

Gas reserve additions in 2010 came from new discoveries (24.3 billion cubic metres), revisions (33.2 billion cubic metres) and development drilling (25.3 billion cubic metres). The gains came mainly from PSAC area 2 (the foothills front zone).

As of Dec. 31, 2010, the ERCB estimated remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 1.03 trillion cubic metres (about 36.39 trillion cubic feet) with a total energy content of about 40 exajoules. This represents a decrease of 30.6 billion cubic metres since the end of 2009.

Reserve additions of gas in Alberta have generally not kept pace with production since 1995.

The ERCB estimates 4.5 trillion cubic metres of unproduced gas remain in the province, of which 1.7 trillion could be produced with current technologies.

The board, however, has embarked on a large-scale resource assessment of shale gas potential in Alberta and that could increase the numbers materially. The resource potential of some shale gas formations will be completed next year.

ALBERTA TIGHT GAS PLAYS PROVE ENTICING

Alberta's Deep Basin has long been known as a multi-zone natural gas area, but today it's attracting renewed interest from operators using new technologies in both vertical and horizontal wells in the search of tight gas and in some cases, light oil.

Peyto Exploration and Development Corp., a veteran Deep Basin player, is using horizontal multi-frac technology to develop new tight gas plays in the Cadotte and Wilrich formations along with its historical vertical activity.

Up until last year, the company had been successfully drilling vertical wells in the Cardium and the Notikewin formations, Dave Thomas, vice-president of exploration, said recently. The new technology has enabled it to add a "brand new" widespread ocean beach sand target in the Wilrich and a "brand new river channel sand target in the form of the Cadotte," he said.

The new horizontal technology is also providing Peyto with stronger production rates in its older Cardium and Notikewin targets, much of it where it already has infrastructure.

In 2010, with natural gas out of favour, Peyto acquired about 100 sections (64,000 net acres) of land inside or complementary to its core areas, at an average price of $195 per acre. The company added mineral rights to target deeper formations, to the base of the Spirit River group or the Bullhead group, to pick up the Notikewin, Falher, Wilrich or Cadomin zones.

At this year's Crown land sale in March, some of the parcels in the area were going for two, three, five and sometimes 10 times what Peyto paid, said Glenn Booth, vice-president of land.

REPORT SAYS NATURAL GAS A "SUSTAINABLE" ENERGY SOURCE

With the emergence of North American shale gas, the world in which Canada's natural gas industry operates has fundamentally changed and public policy needs to be adapted judiciously to deal with this new reality, says a new report from the Canada West Foundation.

"Natural gas has been good for Canada for over half a century," says author Michael Cleland, the foundation's Nexen Executive-in-Residence, in his study entitled *Seismic Shifts: The Changing World of Natural Gas*. "With sound public policy, it will continue to be good for Canada far into the century ahead."

The report envisions a world in which natural gas potentially underpins "a truly sustainable 21st century energy revolution," with the promise of expansion into Asian markets as it continues to generate economic opportunities and fiscal returns to governments.

"Natural gas is abundant, has relatively low emissions and may be the only part of the energy system not facing increasing commodity costs in the coming decade," says Cleland. "It is a natural foundation fuel in an increasingly carbon-constrained world."

GAS DEMAND FOR OIL SANDS TO ALMOST TRIPLE BY 2020: ZIFF

Industry consultancy firm Ziff Energy Group expects natural gas consumption in the Alberta oil sands will grow to about three billion cubic feet per day in 2020 from about 1.1 billion cubic feet per day currently, says vice-president Bill Gwozd.

He said Ziff gas analyst Julia Sagidova analyzed more than 60 existing, under-construction, approved and proposed oil sands developments. Ziff Energy used this information to forecast growth in gas demand by major oil sands operators through this decade. "Gas demand for the oil sands sector will account for four per cent of the total North America gas demand in 2020," Sagidova said in a press release. That would be up from an estimate of roughly 1.5 per cent of North America's average gas demand today. ▶

Cawood expects bitumen output from the province's oil sands regions will reach between 3.5 million and four million barrels per day by 2020, up from 1.4 million to 1.5 million barrels per day now.

He is confident bitumen output can rise to this level by 2020, even though many of the reservoirs in question haven't been developed yet. He said the forecast assumes some proposed projects won't proceed by 2020, others won't reach their design capacity and production will sometimes be interrupted by events such as fires.

But if all announced projects proceeded and reached design capacity, the oil sands sector would need more than seven billion cubic feet of gas per day by 2020, according to Ziff's tally.

"However, in our realistic case, we think it's closer to three billion cubic feet [per day] by 2020," Cawood said of Ziff's forecast for oil sands gas needs. But if the industry is aggressive "and the stars align, you could actually have a lot more gas requirement for the oil sands," he noted.

With the transportation cost of shipping western Canadian gas east expected to rise, growing gas demand in the oil sands sector is "fantastic" news for the region's gas producers, Cawood said.

"As it gets more expensive to [ship gas east], they can find markets here in Alberta ... a made-in-Alberta solution," he said.

GAS PROCESSING PROJECTS ON THE UPSWING

A midstream operator in Alberta is poised for growth over the next few years as natural gas producers pursuing liquids-rich resource plays increasingly embrace and use its services.

"There is a mindset change with the senior producers in terms of midstream and utilizing midstream and investing [their] capital more on reserves," David Cornhill, chairman and chief executive officer of AltaGas Ltd., said. "The Montney shale in B.C. and northwestern Alberta may turn into a mini-oil sands in terms of capital commitment and growth over the next five years from what we're seeing."

In June, AltaGas received final regulatory approval to begin construction of its Gordondale facility, a gas plant that will be able to process 120 million cubic feet per day. It will be located about 100 kilometres northwest of Grande Prairie in the Montney resource area. The $235-million facility will be on stream at the end of 2012 and will be a deep-cut plant producing a C$_3$+ plus mix (ethane and natural gas liquids).

There is no direct competition in the area for deep cut, said Cornhill, adding that AltaGas has been encouraged by the response it has received from producers since the original announcement of the Gordondale plant. It is also seeing "good potential" to be able to expand the facility down the road.

"I don't want to get too far ahead; we haven't built the plant yet, so we don't want to jump the gun here. But clearly from the drilling activity and the producer response and discussions with our lead customer [Encana Corporation], we think there's a high probability of being able to expand that."

Besides the Gordondale facility, another major project is the company's Harmattan co-stream project, which is on schedule to be in service late in the first quarter of 2012. The $430-million development, which will produce an additional 10,000-13,000 barrels per day of C$_3$+ plus, is backstopped by a long-term agreement with NOVA Chemicals Corporation.

The co-stream project will allow 250 million cubic feet per day of rich, sweet natural gas to be processed using spare capacity at the Harmattan Complex, located northwest of Calgary, to recover ethane and natural gas liquids. It will expand the availability of valuable feedstock for Alberta's petrochemical industry, and retain extraction revenues and value in Alberta in an economical manner.

The project involves constructing and operating two new large-diameter, high-pressure, sweet natural gas pipelines, and one small-diameter, high-vapour-pressure product pipeline, as well as modifying existing equipment for processing gas at the complex. Cornhill said pipeline construction is expected to begin in August.

LNG PROJECTS WILL REQUIRE SIGNIFICANT NEW PIPELINE CAPACITY

An estimated $50 billion-$60 billion in new pipelines and liquefaction terminals will be needed over the next five to 10 years if western Canadian natural gas producers are to take full advantage of liquefied natural gas (LNG) opportunities in Asia.

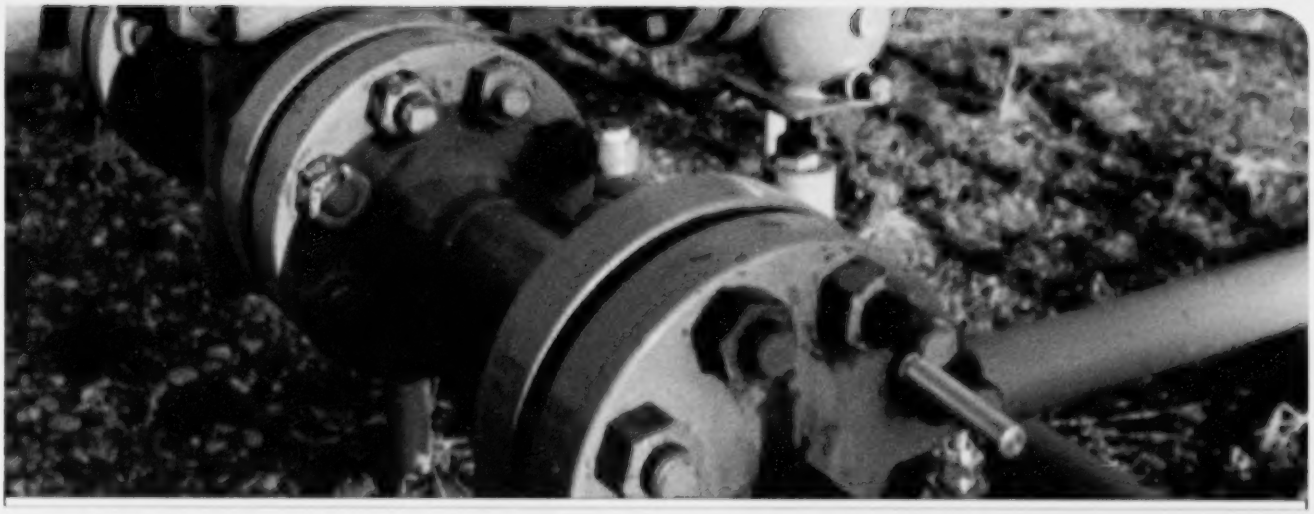
"There's an awful lot of gas in the eastern part of B.C. and the northwestern part of Alberta and to get that gas to Asian markets will certainly require some robust pipeline infrastructure," Tom Latham, managing director of Houston-based LNG Partners LLC, said. The company is a 50 per cent partner with the Haida First Nation in the development of a small-scale LNG project in the Douglas Channel at Kitimat, B.C.

An application from B.C. LNG Export Co-Operative LLC for a 20-year export licence application is currently before the National Energy Board (NEB).

The board is expected to render a decision shortly on an application for an export licence from KM LNG Operating General Partnership with partners Apache Canada Ltd., Encana Corporation and EOG Resources Canada Inc. Several other companies have indicated that they are considering LNG options for their gas.

Although LNG Partners has secured all of the available pipeline capacity on the Pacific Northern Gas (PNG) pipeline system that only equates to about one-three billion cubic feet cargo per month (55,000 tonnes-60,000 tonnes), said Latham. "That doesn't do much for the resource base available."

Export facilities of six billion cubic feet per day to seven billion cubic feet per day of LNG could be built without jeopardizing Canadian supply, he suggested. It would take a two to three large-diameter pipelines to move these sorts of volumes to the North Coast, he said. "There's a mountain range ... so it's



not exactly easy pipeline terrain." There also would need to be additional facilities to move the gas south to Summit Lake because there currently is no capacity for that.

Liquefaction facilities for 50 million tonnes per annum or seven billion cubic feet per day would cost an estimated $40 billion–$50 billion, while INGA Partner's internal estimates peg the cost of two 36-inch systems and a 48-inch system or a 42-inch pipeline with a number of compressor stations and a 48-inch pipeline, at a minimum of $30 billion, Latham said.

PSAC FORECASTS 13,325 WELLS RIG RELEASED IN 2011

In a June update to its Canadian drilling activity forecast, the Petroleum Services Association of Canada (PSAC) said 13,325 wells will be rig released in 2011, up 375 wells from its April forecast.

In April, PSAC revised its 2011 forecast to a total of 12,950 wells drilled (rig released) across Canada, representing a seven per cent increase in total wells drilled compared to 2010.

PSAC is now forecasting a further increase to 13,325 wells for 2011. This amounts to an increase of 10 per cent over 2010 in total wells drilled (rig released) across Canada.

PSAC is basing its updated 2011 forecast on average natural gas prices of C$3.75 per thousand cubic feet (AECO) and crude oil prices of US$99 per barrel (West Texas Intermediate).

The second quarter saw a slightly higher number of 176 more rigs released than was forecasted in the second quarter. Despite severe wet weather in southeastern Saskatchewan and Manitoba, the increase in rigs released was largely due to a shift of activity to other areas, most notably to west central Saskatchewan.

On a provincial basis for 2011, PSAC now forecasts the greatest increase in well count to take place in Saskatchewan with 3,273 wells, an increase of 17 per cent over 2010 numbers. Manitoba is only slightly trailing with a 14 per cent forecasted increase to 590 wells. Alberta will keep pace at 8,761 wells to be drilled, an eight per cent increase, and British Columbia will see a slight increase of two per cent with 660 wells to be rig released.

CARDIUM HAS LIQUIDS-RICH POTENTIAL

While central Alberta's Cardium play is a well-publicized target for light oil–related exploitation, liquids-rich natural gas pursuits in the play may offer comparable economics to crude programs in the formation.

Brad Hayes, president of Petrel Robertson Consulting Ltd., said there is strong liquids-rich potential in the Cardium, but the trick is to identify the "maturity of the source rocks that feed into" the hydrocarbon content. In general, he said, the deeper and more mature the rock, the more gas-prone an area is, while the less mature and a bit shallower the rock, the more likely the reservoir is crude bearing. Liquids-rich hydrocarbons are found somewhere in between the two.

"I would say that in terms of liquids-rich gas specifically, you're going to be looking at the peration sort of intermediate between the deepest plays in the real deep foothills pools where there's some Cardium gas and as you head towards Wapiti to the north, and you head towards Pembina in the south and the east, you're going to get more and more liquids content," he said.

"The location with respect to the source rock maturity is more important than the actual liquids content of the hydrocarbons. In terms of reservoir quality, that's the big controller of the rates you're going to get."

Given the relatively strong economics of liquids-rich gas programs, Hayes said he wouldn't be surprised if there is an uptick in such activity in the Cardium going forward.

"I think so. The real big focus to date has been the oil in Pembina and the Pembina halo, and then the other Cardium fields that are similarly relatively shallow and where you would expect to get the oil," he said.

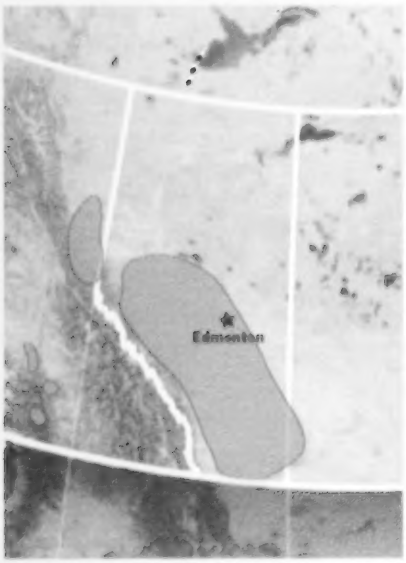
"I don't think the same amount of attention has been paid yet to the deeper areas where you would expect liquids-rich gas, so as more companies target these areas realizing that's what they're going to get when they drill there, I'm sure you will see more activity in these areas." ■

Facts & Figures

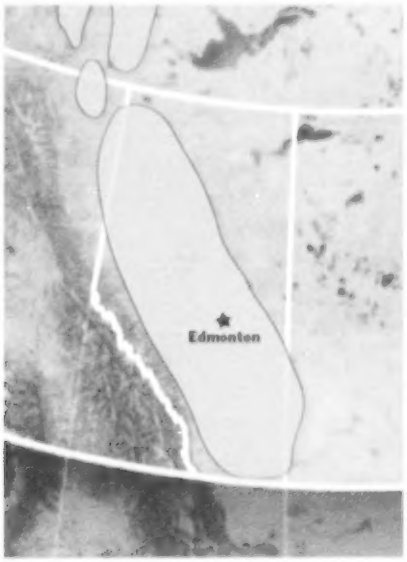
Recent information and statistics on the natural gas industry

As of September 2011

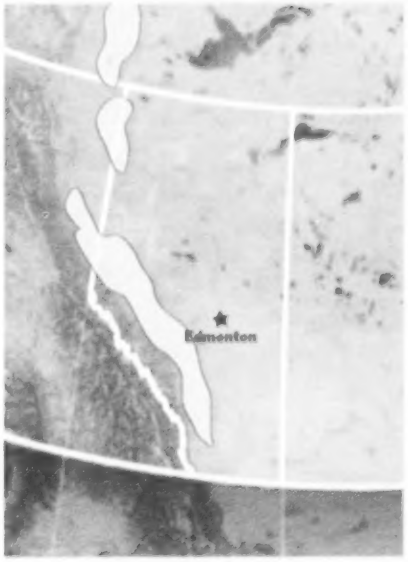
COALBED METHANE



SHALE GAS



TIGHT GAS



COALBED METHANE (CBM):

The Alberta Geological Survey estimates there may be up to 500 trillion cubic feet of natural gas in Alberta's coals. It is not known how much of this gas may be economic to produce. As more information becomes available, the production potential will become clearer.

Approximately 95 per cent of the coalbed methane wells drilled in Alberta have targeted the thinner coal seams in the Horseshoe Canyon (gas in place 71 trillion cubic feet) and Belly River coal zones along the Calgary-Red Deer corridor. Wells targeting these seams tend to produce gas with little or no water. The depth range of these coals is 200-800 metres.

Most of the remaining CBM wells drilled have targeted the deeper Mannville coals (gas in place 239 trillion cubic feet). These coals tend to be thicker, deeper and more continuous with substantial saline (salt) water production. The depth range of these coals is 900-1,500 metres.

Despite depressed natural gas prices over the past few years, Encana Corporation, Quicksilver Resources Inc. and other companies are still drilling CBM wells. Encana's second-quarter 2011 CBM production was 476 million cubic feet equivalent per day, which was 12 per cent higher than the second quarter of 2010 as a result of successful drilling, acquisitions and third-party production. The company drilled 320 net wells and brought 538 new wells on stream. For 2011, it plans to drill 450 net wells.

Encana also reports it is doing more pad drilling this year to allay land disturbance concerns in more populated rural operating areas, but also to reduce its supply cost on this resource play to around $3 per thousand cubic feet.

The top producers from the Horseshoe Canyon coals are Encana, Quicksilver, Nexen Inc., and Apache Canada Ltd. Nexen and Trident Exploration are the leaders in the Mannville coals.

According to an Energy Resources Conservation Board's (ERCB) 2010 summary of reserves and production, CBM contributed 261 million cubic feet and "activity in CBM has increased from a few test wells in 2001 to more than 16,000 producing connections [wells] in 2010."

Currently, 86 per cent of producing CBM wells are in the Horseshoe Canyon. In 2010, CBM contributed eight per cent of Alberta's total marketable gas production, which the ERCB projects will increase to 13 per cent by 2020.

SHALE GAS:

Shale gas exploration and development in the Western Canadian Sedimentary Basin has undoubtedly been accelerated by the continued success of several prolific U.S. shale basins.

The potential for Canadian shale gas production is still being evaluated. In northeastern British Columbia, the most advanced shale gas plays are found in the Horn River Basin, and to a lesser extent in the Cordova Embayment. A number of companies exploring in these regions have advanced their exploration efforts to a point where pilot projects with multiple wells have been completed and natural gas is being produced and sold via the Spectra pipeline system.

Large-scale commercial development will be dependent on market conditions.

According to the ERCB, shale gas exploration and production is in its infancy in Alberta, so currently there is limited data to estimate the shale gas resource potential in the province. Knowledge obtained from American projects indicates that shale gas has the potential to add substantially to Alberta's resource and reserve base. The ERCB is currently evaluating the shale gas resource potential of all prospective shale gas formations in Alberta.

Current exploration and production is constrained by poor market conditions, but two new emerging plays in Alberta are the deep Duvernay Formation and Colorado Group shales located in the western part of the province. Limited testing has taken place with encouraging results, but no commercial projects have been developed to date.

TIGHT GAS:

The Western Canadian Sedimentary Basin is host to most of Canada's conventional natural gas resources and within this basin, the northern and western regions contain much of the tight gas potential.

Total original gas in place (OGIP) is estimated at 1,311 trillion cubic feet. Other regions within Canada, specifically the Mackenzie Delta in the Arctic and the Albert Formation in the Maritimes, are believed to have tight gas resource potential, but no estimates have been made due to lack of geological data.

While the OGIP value is very large, only a portion of these resources are deemed technologically recoverable. Marketable resources are estimated at between 230 and 509 trillion cubic feet, with half attributed to the Deep Basin and the Montney in Alberta, and the rest to various accumulations in northeastern British Columbia.

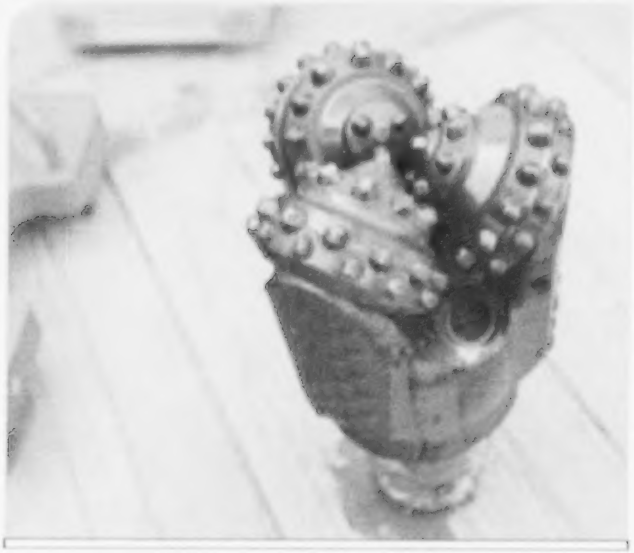
NATURAL GAS LIQUIDS (NGLs):

Natural gas liquids (NGLs) are recovered mainly from the processing of natural gas in Alberta. Field gas-processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated in specification products. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas and are usually located on the main gas transmission pipelines at border delivery points.

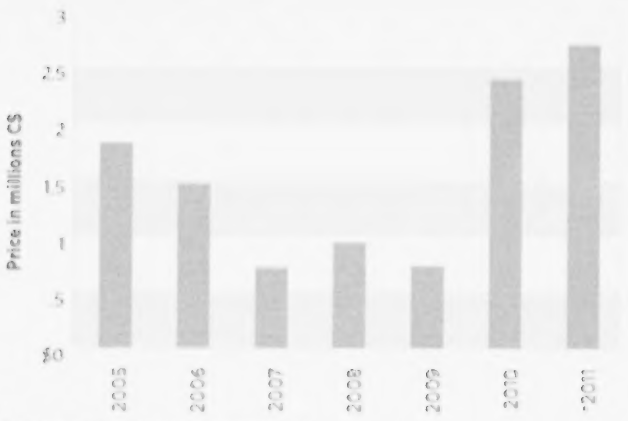
In Alberta, there are about 550 active gas processing plants that recover NGL mix or specification products, 10 processing plants that fractionate NGL mix streams into specification products and nine straddle plants.

Remaining established reserves of extractable ethane is estimated to be 113 million cubic metres (716 million barrels). The remaining established reserves of other NGLs – propane, butane and pentanes plus – is 148 million cubic metres (932 million barrels).

All of the specification ethane extracted from natural gas was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The petrochemical industry in Alberta is benefiting from the low gas price environment since the price of ethane is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost-advantage for ethylene production compared to other regions in North America. ■



ALBERTA CROWN LAND SALES



*Numbers for 2011 include sales up to September 7.

DRILLING RIG COUNT BY PROVINCE/TERRITORY

Western Canada Sept. 15, 2011

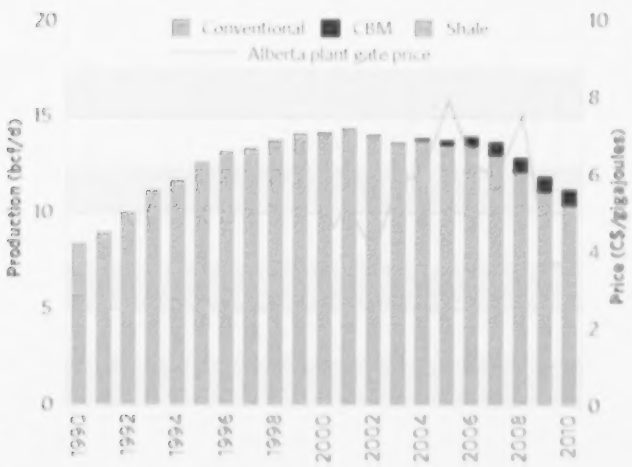
	ACTIVE	DOWN	TOTAL	ACTIVE (Per cent of total)
Western Canada				
Alberta	373	186	**559**	67%
British Columbia	53	28	**81**	65%
Manitoba	18	1	**19**	95%
Saskatchewan	116	33	**149**	78%
WC Total	**560**	**248**	**808**	**69%**
Northwest Territories	0	0	**0**	0%

DRILLING ACTIVITY: OIL & GAS BY PROVINCE/TERRITORY

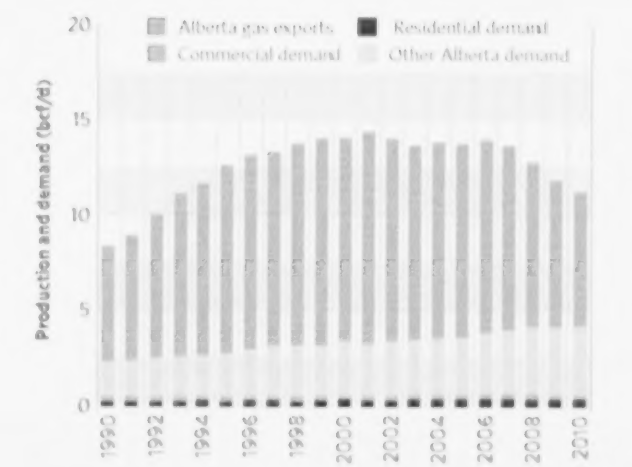
Alberta August 20, 2011

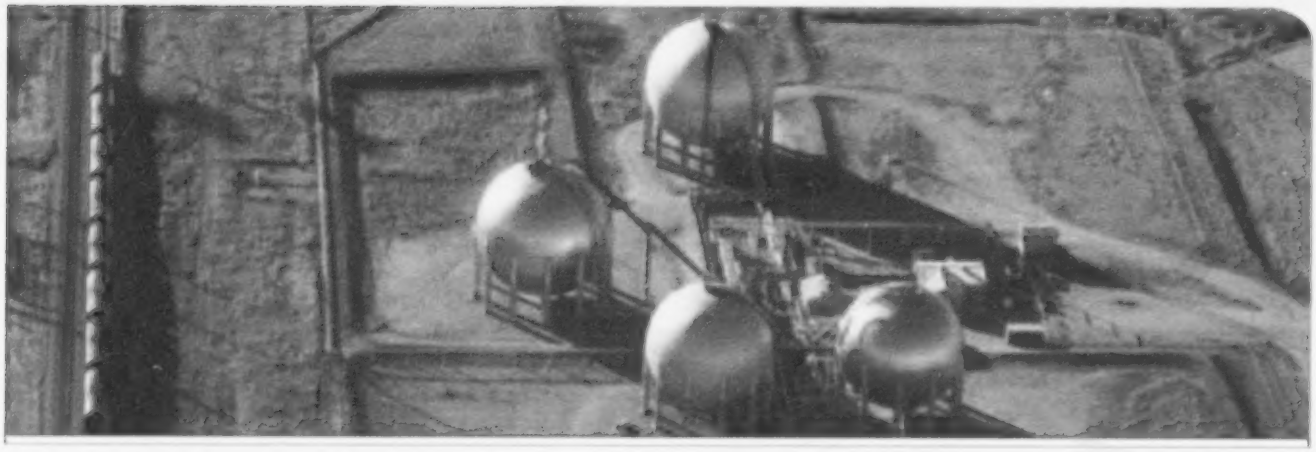
	OIL WELLS		GAS WELLS	
Western Canada	**August 2011**	**August 2010**	**August 2011**	**August 2010**
Alberta	452	171	183	135
British Columbia	7	2	77	9
Manitoba	49	83	–	–
Saskatchewan	413	199	2	12
Total	**921**	**455**	**262**	**156**
Northwest Territories	0	0	0	0%

ALBERTA MARKETABLE GAS PRODUCTION

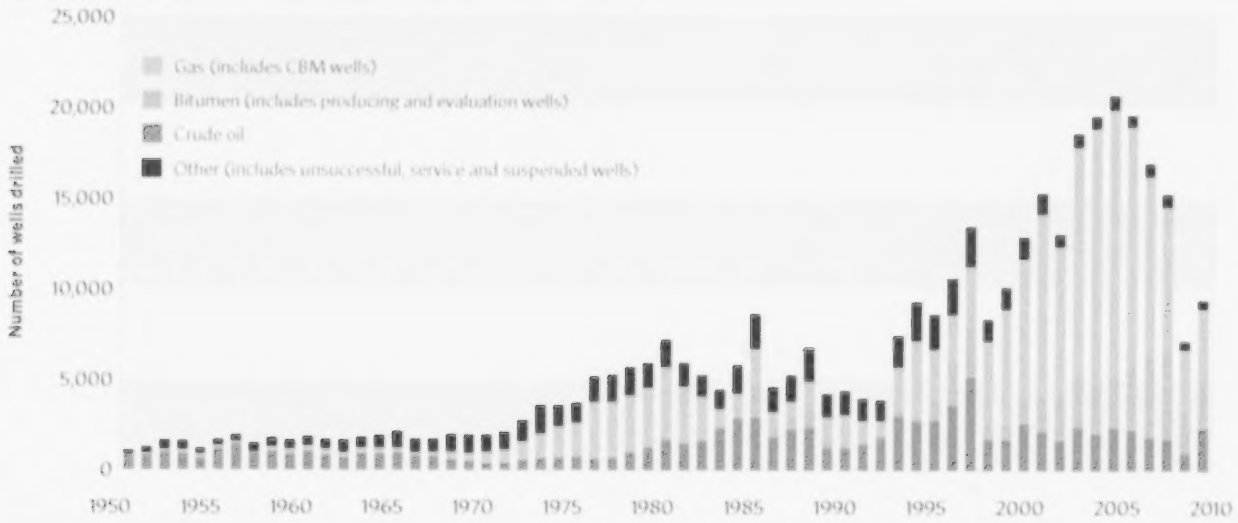


ALBERTA MARKETABLE GAS DEMAND

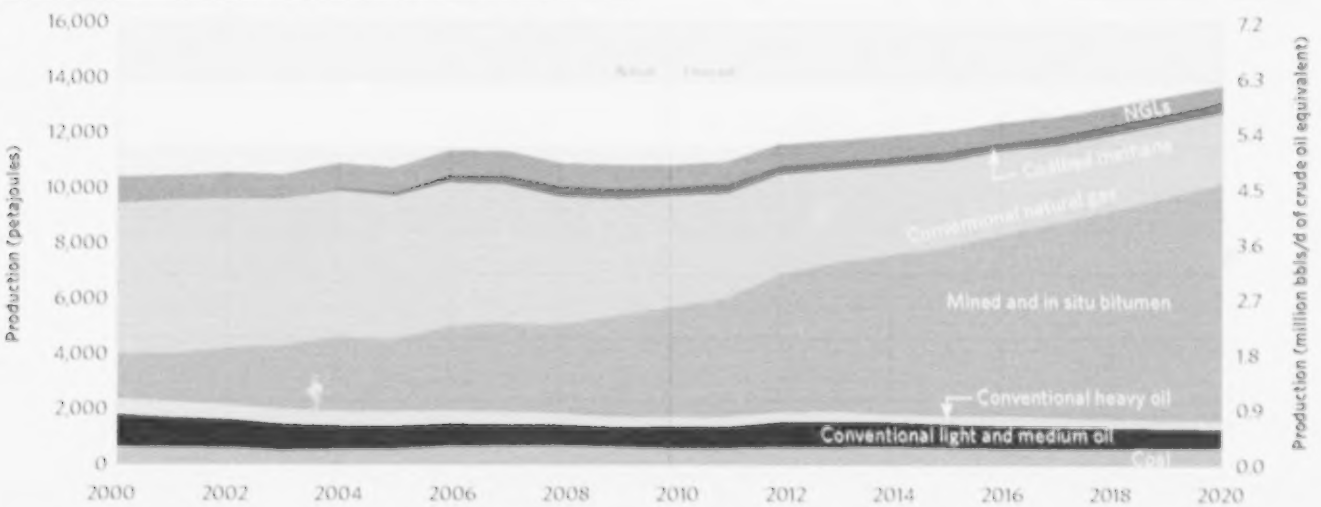




DRILLING ACTIVITY IN ALBERTA, 1950-2010



TOTAL PRIMARY ENERGY PRODUCTION IN ALBERTA



Glossary of natural gas terms

Abandoned well:
A well that is permanently shut down because it was a dry hole or because it has ceased to produce crude oil or natural gas.

Acid gas:
Hydrogen sulphide (H_2S) or carbon dioxide (CO_2) or a combination of H_2S and CO_2, which are referred to as acid gases because they form acids or acidic solutions in the presence of water.

Audits:
Actions taken by staff or a third party to help measure a company's compliance with legislation and internal requirements, and to identify opportunities for improvement. Audits can involve field inspections, interviews with management and document review.

Blowout preventer (BOP):
Equipment that is installed at the wellhead to control pressures and fluids and to prevent uncontrolled fluid flow from the reservoir during drilling, completion and certain remedial operations to restore production.

Broker:
An individual or independent corporation engaged in bringing together sellers and buyers of natural gas, assisting in negotiations, and arranging transportation and delivery terms. Brokers usually do not buy or sell for their own account but act as an agent for the buyer and/or seller.

Burner-tip:
The point of end-use consumption of a particular fuel, such as natural gas or residual fuel oil.

Burner-tip price:
The price of natural gas (or other fuels) paid by the final consumer. For natural gas, this includes the price of the gas plus the cost of processing, gathering, transmitting and distributing it.

Butane (C_4H_{10}):
A natural gas liquid (NGL) used as a household fuel, refrigerant and aerosol propellant and in the manufacture of synthetic rubber.

Caprock:
Impermeable rocks such as shale that overlie the reservoir rock and trap natural gas and crude oil in the reservoir. Also, impermeable rock overlying a geothermal reservoir. Also called sealing rock.

Carbon dioxide (CO_2):
A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities.

Carbon monoxide (CO):
Colourless, odourless, poisonous gas produced by incomplete combustion of fossil fuels.

Coalbed methane:
Natural gas generated during the coalification process and trapped within coal seams, commonly referred to as natural gas from coal.

Commingled gas:
A homogeneous mix of natural gas from various physical (or contractual) sources.

Completion:
Preparing a newly drilled well for production; usually involves setting casing—pipe that lines the interior of a well to prevent caving and protect against groundwater contamination—and perforating the casing to establish communication with the producing formation.

Compressed natural gas (CNG):
Natural gas in its gaseous state that has been compressed to about one per cent of its volume and stored at 20,000–27,500 kilopascals.

Condensate:
A mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas. While it can be used to make gasoline, jet fuel and other products, it is primarily used in Alberta as diluent.

Conventional gas:
Natural gas that can be produced using recovery techniques normally employed by the oil and gas industry. The distinction between conventional and unconventional gas is becoming less clear. See also *unconventional gas*.

Deep cut:
The processes that recover NGLs from natural gas in excess of amounts required for sales gas to meet pipeline specifications.

Deliverability:
The amount of natural gas a well, field, gathering, transmission or distribution system can supply in a given period of time.

Directional drilling:
Drilling a wellbore at any angle other than vertical; used where the rig cannot be set up directly over the target, or to drill more than one hole from a single location.

Downstream:
The refining and marketing sector of the petroleum industry.

Dry gas:
Natural gas from the well that is free of liquid hydrocarbons, or gas that has been treated to remove all liquids; pipeline gas.

Energy Resources Conservation Board (ERCB):
An independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development and delivery of Alberta's energy resources take place in a manner that is fair, responsible and in the public interest.

Established reserves:
Generally defined as proved reserves, plus one half probable reserves.

Ethane (C_2H_6):
An NGL, the uses of which include enhanced oil recovery, as a fuel and as a feedstock for the petrochemical industry.

Flaring:
Controlled burning of natural gas that cannot be processed for sale because of technical or economic reasons. The biggest portion is solution gas flaring, which involves the burning of natural gas produced along with crude oil and bitumen.

Fracturing (or fracking):
A reservoir stimulation technique in which fluids are pumped into a potentially productive formation under high pressure to create or enlarge fractures allowing the oil or gas to flow from the zone at higher rates. In some operations, proppants such as frac sand are injected with the frac fluid to help hold the rock fractures open.

Gas:
One of the three states of matter, gas is characterized by having neither shape nor specific volume; it expands to fill the entire container in which it is held.

Gas processing plant:
Any facility that performs one or more of the following: removing liquefiable hydrocarbons from wet gas or casinghead gas; removing undesirable gaseous and particulate elements from natural gas; removing water or moisture from the gas stream.

Gas reservoir:
A porous and permeable rock formation in which natural gas accumulates.

Gas transmission systems:
Pipelines that carry natural gas at high pressure from producing areas to consuming areas.

Gathering system:
A system of small-diameter plastic or steel pipes (gathering lines) transporting natural gas from producing wells to field facilities.

Horizontal drilling:
Drilling horizontally through a reservoir to increase the exposure of the formation to the well.

Hydrocarbons:
A large class of liquid, solid or gaseous organic compounds, containing only carbon and hydrogen, which are the basis of almost all petroleum products.

Hydrogen sulphide (H_2S):
A naturally occurring, highly toxic gas with the odour of rotten eggs.

Inert gases:
Gases that are unable to or unlikely to react with any other substance.

Injection (oil and gas):
Injection enhancement technique wherein water or other substances are injected into an oilfield to improve production. Also, the re-injection of natural gas into an oilfield to maintain reservoir pressure.

Inlet separation:
The initial stage of processing at a natural gas processing plant where the incoming raw gas stream enters a vessel and any free liquids, such as water and NGLs, are removed from the gas stream before it is further processed.

Land:
In the petroleum industry, "land" often refers to the oil and gas rights on a particular area of land. For example, in a "land sale," the oil and/or gas rights are "sold" (although in reality the rights are leased).

Landman:
A male or female member of the exploration team whose primary duties are managing a petroleum company's relations with its landowners and partners, including securing and administering oil and gas leases and other agreements. Other duties include helping to formulate exploration and development strategies. Also known as a land agent or land person.

Lease agreement:
The negotiated legal document giving an oil and gas company the right to utilize the surface lease site to drill for and produce oil or gas.

Liquefied natural gas (LNG):
Supercooled natural gas that is maintained as a liquid at or below -160°C; LNG occupies 1/640th of its original volume and is therefore easier to transport if pipelines cannot be used.

Manufactured gas:
A gas obtained by destructive distillation of coal, by the thermal decomposition of oil or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke or oven gases, producer gas, blast furnace gas, blue (water) gas or carbureted water gas (also known as syngas).

Methane (CH_4):
Methane consists of one carbon atom and four hydrogen atoms and is the largest component of natural gas. Methane remains in a gaseous state at relatively low temperatures and pressures. Methane is also produced when organic matter decomposes.

Midstream sector:
Primarily the processing, storage and transportation sector of the energy industry.

Mineral rights:
The rights to explore for and produce the resources below the surface. In the petroleum industry, mineral rights can also be referred to as "land."

National Energy Board (NEB):
The federal regulatory agency in Canada that authorizes oil, natural gas and electricity exports; certifies interprovincial and international pipelines, and designated interprovincial and international power lines; and sets tolls and tariffs for oil and gas pipelines under federal jurisdiction.

Natural gas:
Gaseous petroleum consisting primarily of methane with lesser amounts of (in order of abundance) ethane, propane, butane and pentane, and heavier hydrocarbons as well as non-energy components such as nitrogen, carbon dioxide, hydrogen sulphide and water.

Natural gas liquids (NGLs):
Liquids obtained during production of natural gas, comprising ethane, propane, butane and condensate.

Non-associated gas:
Natural gas that is produced from reservoirs that contain only natural gas, and is therefore not associated with crude oil production.

Operator:
The company responsible for managing an exploration, development or production operation.

Orphan wells:
Wellsites for which the licence operators have ceased to exist or cannot be traced.

Pentane (C_5H_{12}):
A hydrocarbon compound consisting of five carbon atoms and 12 hydrogen atoms.

Petroleum:
A naturally occurring mixture composed predominantly of hydrocarbons in the gaseous or liquid phase.

Probable reserves:
Reserves believed to exist with reasonable certainty based on geological information.

Propane (C_3H_8):
An NGL used as a fuel (i.e., in barbeques, transportation and heating of households in areas where natural gas supply is not available).

Proppant:
Sand, or ceramic or resin beads pumped into a wellbore at the end of the fracturing process to prop open newly induced fractures and enhance permeability.

Proved reserves:
Reserves that can be economically produced with a large degree of certainty from known reservoirs using existing technology.

Raw natural gas:
A mixture containing methane plus all or some of the following: ethane, propane, butane, condensates, nitrogen, carbon dioxide, hydrogen sulphide, helium, hydrogen, water vapour and minor impurities. Raw natural gas is the gas found naturally in the reservoir prior to processing.

Recoverable resources:
Hydrocarbon reserves that can be produced with current technology, including those not economical to produce at present.

Renewable energy:
Naturally occurring energy sources that are continually replenished. Examples of renewable energy are wind, solar and water.

Reserves:
Recoverable portion of resources available for use based on current knowledge, technology and economics.

Reservoir (oil and gas):
A porous and permeable underground rock formation containing a natural accumulation of crude oil or natural gas that is confined by impermeable rock or water barriers, and is separate from other reservoirs.

Sales gas:
Natural gas that has been treated in a natural gas processing facility and is suitable for sale. Some of the processes that natural gas may undergo are inlet separation, gas treating, dehydration and NGL recovery, before it enters a transmission pipeline for eventual transportation to market.

Shale gas:
Natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.

Solution gas:
Natural gas that is dissolved in crude oil in underground reservoirs. When the oil comes to the surface, the gas expands and comes out of the oil.

Sour gas:
Raw natural gas with a relatively high concentration of sulphur compounds, such as hydrogen sulphide. All natural gas containing more than one per cent hydrogen sulphide is considered sour. About 30 per cent of Canada's natural gas production is sour, most of it found in Alberta and northeastern British Columbia.

Source rock:
The rocks in which hydrocarbons are created or sourced from carbohydrates through heat and pressure. Source rocks are often black shales.

Straddle extraction plant:
A gas processing plant located on or near a gas transmission line that removes natural gas liquids from the gas and returns it to the line.

Sulphur recovery:
Sour gas is processed at recovery plants to extract sulphur for sale to fertilizer manufacturers and other industries in Canada and overseas. The average rate of sulphur recovery at Alberta's sulphur recovery plants has improved from 97.5 per cent in 1980 to 98.8 per cent in 2000.

Sweet gas:
Raw natural gas with a relatively low concentration of sulphur compounds, such as hydrogen sulphide.

Syngas:
A fuel produced from solid hydrocarbons such as coal and petroleum coke. The process uses steam, air and controlled amounts of oxygen to break the solid down, and the resulting gas consists of vaying amounts of carbon monoxide and hydrogen.

Tight gas sands:
Natural gas that is found in sandstone with low permeability.

Trunk lines:
Large-diameter pipelines that transport crude oil, natural gas liquids and refined petroleum products to refineries and petrochemical plants; some trunk lines also transport refined products to consuming areas.

Unconventional natural gas:
In the case of natural gas from coal, natural gas from tight sands and shale gas, conventional gas found in unconventional reservoirs or reservoirs requiring special production methods or technologies; in the case of gas hydrates, conventional methane in an unconventional form occurring in a conventional reservoir.

Upstream:
Refers to companies that explore for, develop and produce petroleum resources (in contrast, downstream refers to the refining and marketing components of the industry).

Western Canadian Sedimentary Basin (WCSB):
Canada's largest region of sedimentary rocks; the largest source of current oil and gas production, covering all of Alberta and parts of Manitoba, Saskatchewan, British Columbia and the Yukon.

Wet gas:
Raw natural gas with a relatively high concentration of natural gas liquids (ethane, propane, butane and condensates).

CONTACTS

Industry Associations

• Alberta Land Surveyor's Association	www.alsa.ab.ca
• Canadian Association Geophysical Contractors	www.cagc.ca
• Canadian Association of Oilwell Drilling Contractors	www.caodc.ca
• Canadian Association of Petroleum Producers	www.capp.ca
• Canadian Energy Pipeline Association	www.cepa.com
• Canadian Gas Association	www.cga.ca
• Canadian Natural Gas	www.canadiannaturalgas.ca
• Canadian Natural Gas Vehicle Alliance	www.cngva.org
• Canadian Society of Exploration Geophysicists	www.cseg.ca
• Canadian Society of Petroleum Engineers	www.speca.ca
• Canadian Society for Unconventional Resources	www.csur.ca
• Gas Processing Association Canada	www.gpacanada.com
• Petroleum Services Association of Canada	www.psac.ca
• Petroleum Technology Alliance Canada	www.ptac.org
• Small Explorers and Producers Association of Canada	www.sepac.ca

Alberta Government

• Alberta Energy	www.energy.gov.ab.ca
• Alberta Environment	www.environment.alberta.ca
• Alberta Finance and Enterprise	www.finance.alberta.ca
• Alberta Geological Survey	www.ags.gov.ab.ca
• Alberta Innovates	www.albertainnovates.ca
• Alberta Surface Rights Board	www.surfacerights.gov.ab.ca
• Alberta Sustainable Resource Development	www.srd.alberta.ca
• Energy Resources Conservation Board	www.ercb.ca

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